Decision 01-08-021 August 2, 2001

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (E 3338-E) for Authority to Institute a Rate Stabilization Plan with a Rate Increase and End of Rate Freeze Tariffs.	Application 00-11-038 (Filed November 16, 2000)
Emergency Application of Pacific Gas and Electric Company to Adopt a Rate Stabilization Plan. (U 39 E)	Application 00-11-056 (Filed November 22, 2000)
Petition of THE UTILITY REFORM NETWORK for Modification of Resolution E-3527.	Application 00-10-028 (Filed October 17, 2000)

INTERIM OPINION ADDRESSING REAL TIME PRICING ISSUES AND MODIFYING DECISION 01-05-064

1. Summary

In this decision, we address two petitions by the California Energy Commission (CEC) to modify portions of Decision (D.) 01-05-064 related to Real Time Pricing (RTP) issues.

We grant, in part, CEC's May 17, 2001 petition and modify D.01-05-064 to (1) clarify that the receipt of interval meters for customers with electric loads over 200 kilowatts (kW) of demand is mandatory under Assembly Bill 29X; and (2) provide customers receiving these meters who are not on a Time of Use (TOU) rate schedule the choice of participating in a demand reduction program administered by the Commission or switching to a TOU schedule.

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We do not adopt the pro-forma tariff proposed by the CEC in its June 21, 2001 petition. We find the proposal is not based on real-time prices; does not provide an estimate of the dollar amount of incentives that will need to be paid under the proposal and the impact this would have on the CDWR revenue requirement; raises significant concerns that the plan proposed by CEC would result in cost shifting from large customer classes to the small business, agricultural, and residential classes; dilutes the positive load reduction effects of the rate increase, the 20/20 program, and the system benefits of subsidized energy efficiency improvements; and would not be compatible with existing demand reduction programs administered by the Commission, CDWR, and the ISO. Perhaps most troubling is that the CEC proposal would have the Commission unlawfully delegate its ratemaking authority.

While many, although perhaps not all, of our concerns with the CEC's proposal could be addressed by additional time, we realize the significant constraints the CEC was operating under in attempting to have a program operational for this summer. We plan to follow up on the CEC's initiative. To assist all parties, we are laying out the guidelines that we believe an RTP program must have in order to be beneficial. In this decision, we reaffirm our support for an RTP program and provide specific criteria that we will use to evaluate future proposals. We direct Pacific Gas and Electric Company (PG&E), Southern California Edison Company (Edison), San Diego Gas & Electric Company (SDG&E), and any other interested parties to present RTP proposals that meet these criteria by August 17, 2001.

2. Background

In D.01-05-064, the Commission allocated among customer classes the three-cent-per-kilowatt-hour (kWh) average rate increase authorized to be charged to the customers of CDWR, PG&E, and Edison in D.01-03-082. The rate design we adopted promotes several objectives, chief among them an equitable allocation of costs among customer classes. It also promotes conservation, which we define as reducing total consumption at all hours and also targeting energy reduction at peak hours and other periods when California may face electricity supply shortages.

In our adopted rate design we also sought to provide customers and this Commission with information and technical tools to respond to the wholesale costs and conditions we are facing. To do this, we proposed developing an RTP pilot program and encouraged large commercial customers to use energy meters to better control electrical use at times of greatest price or demand. We directed the Energy Division to begin our RTP process with a workshop on May 21, 2001 and stated we anticipated adopting a final program later this summer.

3. CEC's Petitions to Modify

On May 17, 2001, CEC filed an emergency petition for modification of D.01-05-064. CEC requested the Commission clarify that the meters provided by CEC pursuant to ABX1 29 are to be installed for all customers whose usage is greater than 200 kW at peak demand. CEC stressed that it views ABX1 29 as establishing a mandatory metering program, and that the customer does not have the option to reject the RTP meter CEC has chosen to install.

The requested language provided by CEC would also remove the requirement that customers provided with interval meters under ABX1 29 be shifted to TOU schedules. CEC does not explain why it proposes this modification but parties responding to the proposal state that a mandatory switch to a TOU schedule would be viewed by customers as a penalty. CEC states that due to the urgent status of ABX1 29, the Commission should act on an emergency basis on its petition and considerably shorten any party's time for comment.

Responses to this petition were filed on May 22 by PG&E and the American Energy Institute (AEI). The Commission's Office of Ratepayer Advocates (ORA) filed a response on May 23. All commenters supported CEC's position that the metering program was mandatory and its request that customers not be required to switch to TOU rates. The commenters stated that the TOU-rate requirement would make customers view the new equipment as a penalty rather than as an aid to improving their energy consumption decisions.

The Commission's Energy Division held a workshop on May 21 on RTP issues, pursuant to the directive of D.01-05-064. Following the workshop, a summary report was prepared by Energy Division and served on all parties.

On June 21, the CEC filed a Petition for Modification of D.01-05-064 by proposing an RTP tariff[1]. CEC states that based on input from the May 21 workshop and further dialogue with the Energy Division, the utilities and various customer groups, the CEC developed a pro-forma RTP tariff which it submits in its petition in order to begin the immediate implementation of RTP. The CEC requests an expedited approval process for its pro-forma tariff by having the Commission shorten response time to its petition, grant its illustrative pro-forma tariff, and direct PG&E, Edison, and SDG&E to file conforming tariffs as soon as possible as Advice Letter filings, effective on the date of filing.

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[1] CEC concurrently filed its petition in Rulemaking (R.) 00-10-002, the Commission's proceeding on interruptible load programs offered by PG&E, SDGE, and Edison. By ruling dated July 3, 2001, the presiding officer and assigned Commissioner ruled that because the petition was being considered in Application (A.) 00-11-038 et al., it would not be considered in R.00-10-002.

PG&E and Edison filed responses to CEC's petition on June 28, 2001. Both utilities cite to significant areas of disagreement with CEC's proposal and request the Commission hold an additional workshop prior to considering the petition. On July 3, the assigned Administrative Law Judge (ALJ) issued a ruling shortening time for responses to July 6 and scheduling an Energy Division workshop to discuss RTP issues on July 9. Additional responses to CEC's petition were filed by ORA, Environmental Defense, and the Silicon Valley Manufacturing Group (SVMG) on July 6.

SVMG strongly endorses the CEC's petition, especially its High Reliability Option, and urges expedited Commission approval. Environmental Defense strongly supports CEC's petition, citing the environmental benefits that would arise from customers who respond to RTP by reducing their overall energy consumption or shifting load to off peak hours and the need for Californians to realize a full return on the investment of $35 million in meters under ABX1 29. ORA states it supports CEC's tariff proposal if the High Reliability Option (HRO) provisions are modified.

4. Discussion

We first address CEC's May 17 petition. We agree that ABX1 29 does require mandatory TOU or RTP metering for customers whose usage is greater than 200 kW of peak demand and we will modify Section V.A. **Moving to Time of Use Meters for Commercial Customers** of D.01-05-064 to clarify that meter installation is mandatory under ABX1 29 and reflect CEC's position that it intends to install only RTP meters with the $35 million allocated under ABX1 29. We recognize the concerns of CEC, PG&E, AEI, and ORA that our requirement that customers who receive these meters be shifted to TOU schedules may be viewed as a penalty by customers.

Our intent in requiring mandatory TOU participation for customers receiving upgraded meters under ABX1 29 is to ensure that the state's $35 million investment in the sophisticated metering systems delivers the benefit of reducing California's energy demand, especially at times of supply shortages. Customers can meet this objective by participation in demand reduction programs offered by the Commission, or by being on a TOU rate schedule. CEC's choice of RTP rather than the less expensive TOU metering systems makes it even more beneficial for customers to participate in a demand reduction program, as all of these programs, including RTP, utilize the sophisticated features of RTP metering systems. We include in our discussion of demand reduction programs the new Demand Bidding Program (DBP) adopted by the Commission in D.01-07-025. Attachment A to D.01-04-006, "Changes to Current Interruptible Programs, New Interruptible Programs, and Rotating Outage Programs" will be updated to reflect the new Demand Bidding Program, as it has been updated for other demand reduction programs in D.01-05-090 and D.01-06-087.

We should modify D.01-05-064 to permit customers receiving an RTP metering system who are not already on a TOU schedule to choose to enroll in a demand reduction program included in the revised Attachment A to D.01-04-006, rather than be automatically shifted to a TOU schedule. Customers should make this election within 15 days of installation of the new metering system. Customers failing to choose a demand reduction program or TOU schedule shall be placed on a TOU schedule.

The RTP metering system installation being administered by the CEC pursuant to ABX1 29 covers SDG&E as well as PG&E and Edison. RTP issues involving SDG&E that were to be addressed in A.00-10-045 and A.01-01-044 were transferred to this proceeding by ALJ Wetzell at hearings on June 1, 2001, based on a motion by CEC (Tr. at 352). Therefore, the modified language we adopt here should also apply to SDG&E, who is a party to this proceeding.

To address the issues discussed above, we will modify Section V.A. by deleting the last two paragraphs of the section (mimeo. at 32) and replacing them with the following language:

> Pursuant to ABX1 29, the CEC is authorized $35 million for the installation of TOU or Real Time Pricing (RTP) metering systems on all customers with electric loads over 200 kW of demand. Under this mandatory program, the CEC has chosen to install RTP rather than TOU metering systems. RTP metering systems provide the communication capabilities necessary for customers to participate in specific load reduction programs, DRPs, administered by the Commission, the ISO, and CDWR. These programs, including the proposed Demand Bidding Program (DBP), currently pending before the Commission in R.00-10-002, offer customers incentives for reducing energy consumption and demand during high net short periods. In order for California to realize the benefits of ABX1 29 metering expenditures, all customers who receive the meters should be on a demand reduction program as listed in the revised Attachment A to D.01-04-006 or placed on a TOU schedule. Customers should make this election within 15 days of installation of the new metering system. Customers failing to choose a demand reduction program or TOU schedule shall be placed on a TOU schedule.

In modifying D.01-05-064 to provide customers receiving ABX1 29 metering systems the choice of participating in a demand reduction program or switching to a TOU rate schedule, we should also adopt a monitoring plan to ensure PG&E, Edison, and SDG&E timely install the new meters and to track the selection by customers of a demand reduction program or TOU schedules. To accomplish this, the following paragraph should be added to the end of Section VII.B., **Expedited Installation of Meters**. (Mimeo. at 49.):

> To ensure effective monitoring of timely installation of the meters we should require PG&E, Edison, and SDG&E to provide a bi-weekly report until all ABX1 29 metering systems are installed that lists the number of RTP metering systems installed and the selection made by the customer of a demand reduction program (DRP), as set forth in revisions to Attachment A of D.01-04-006 or enrollment on a TOU schedule. The utilities should prioritize the installation of these meters to first include customers who are enrolled in a demand reduction program and then proceed to customers with the highest kW peak demand level.

We next turn to CEC's June 12 petition proposing a pro-forma RTP tariff. Based on our review of the petition and filed responses, we have significant concerns regarding key provisions of CEC's proposed RTP tariff and therefore do not grant the CEC's petition at this time.

We appreciate the time and effort the CEC devoted to developing its proposal and recognize the significant constraints it was operating under in quickly putting together its proposal. We plan to follow up on the CEC's initiative by requiring the utilities, as well as other interested parties such as the CEC, to file real-time pricing proposals by August 17, 2001 in this proceeding. To assist all parties, we discuss in detail our concerns with the RTP proposal currently before us and, in the next section, we specify the guidelines parties should follow in submitting RTP proposals on August 17, 2001.

In declining to adopt the CEC's RTP proposal, we must first note that it is not a true real-time pricing program because it does not use a transparent real time price.[2] Instead, the CEC states it's proposal "masks" the Day Ahead energy

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[2] With the demise of the Power Exchange, there may not presently exist a real-time market that can be used for an RTP program. The ISO has a real-time market but it is

Footnote continued on next page

procurement prices by attaching an "add factor" that allows additional cost reductions from estimates of avoided ancillary service (A / S) costs that have not yet been priced in the ISO A / S markets and estimates of avoided transmission congestion costs.[3] As Edison comments, the CEC contemplates that the methodolgy for calculating the hourly prices will be developed by CDWR, the Electricity Oversight Board, and the CEC and this would require the Commission to delegate to this committee our ratemaking authority under Section 451 et al., of the California Public Utilities Code.[4]

The CEC's proposal also does not bill all usage at a single price, but rather creates a complex Customer Baseline Load (CBL) mechanism[5] that would pay a customer incentives to reduce load based on how that customer's energy usage varies from an administratively calculated usage pattern. We share the concerns with a CBL mechanism expressed by ORA in its comments.[6] This administrative calculation is complex, with each customer's reference load capable of being calculated in one of three different ways (depending upon the availability of data) and with customers able to request a "customized" calculation that could take into account other factors such as weather and facility outages. Given that

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not robust and parties have not discussed the viability of alternatives, such as hub prices.

[3] CEC's petition at pages 7-8.

[4] Edison June 28 comments at page 2.

[5] In its July 6 comments, ORA notes that SDG&E proposed in the Interruptibles proceeding, R.00-10-002, that a simplified "one-part" tariff be used rather than implementing the CEC's "two-part" tariff involving a CBL.

[6] Id. at pages 4-5.

the CEC plans to install over 20,000 meters, each of which would require an individual reference load, this administrative calculation constitutes a significant administrative burden to the utilities.

Another issue the CEC's proposal raises is the appropriate starting point for determining when a load reduction is assumed to occur. As the Commission can attest to from its experience in its rulemaking on interruptible programs (R.00-10-002), the calculation of the reference load is one of the more difficult issues that need to be resolved in any demand responsiveness program. The reference load calculation must reflect, to the extent possible, the actual energy usage that would occur absent any demand responsiveness program. Otherwise, program participants are being paid either for load reductions that would have occurred anyway, or for phantom (or nonexistent) load reductions that result from an incorrect calculation of the reference load. This results in all other ratepayers paying for nonexistent load reductions, significantly affecting the benefits and cost-effectiveness of any program. In some cases, these costs can outweigh even the societal benefits that the programs may offer.[7]

[7] The societal benefits of demand responsiveness programs are claimed to result from the reduction in energy prices that occur as demand is reduced on the margin. Therefore, not only does the program participant save by reducing his/her energy usage, all other ratepayers benefit by paying a lower market price for the energy they consume. The level of this savings is difficult to determine and depends upon the supply curve for energy and the amount of energy that is being purchased in the spot market. During many off- and mid-peak hours, when supply curves are relatively flat, there may be little or no change in the market price from a reduction in load. The effect is most pronounced during high demand periods but its effect is moderated by the amount of energy that needs to be purchased on the spot market. As CDWR purchases more and more of its energy needs under longer-term fixed price contracts, the societal benefits are likely to become less, and even negative in the event CDWR has to resell power at a loss.

As ORA notes in comments on CEC's proposed RTP tariff, "some conservation credits will be earned for declines in consumption that would have occurred even without the RTP program. This would apply to businesses whose activity is declining for economic reasons…"[8] Any business whose output is less this year than in previous years due to economic conditions could sign-up for the CEC's program and receive payments for these phantom load reductions. While under a mandatory RTP program there may not be a net cost to ratepayers, as those customers whose energy usage is increasing due to economic conditions would offset those who are decreasing, under a voluntary program only those who would benefit have an incentive to sign-up.

This lack of symmetry also affects the ability of customers to seek a "customized" reference load calculation. While every customer has an incentive to advocate for an increased baseline, thus increasing their potential incentive payments, no customer has a corresponding incentive to advocate for a reduced baseline that would make it more likely for the customer to either not receive an incentive, or perhaps even incur penalties under the program.

In order to address the potential for gaming of the reference load calculations, the CEC proposes that the utilities monitor, if necessary, the output and operation of customers participating in the program to ensure that the customer has not "ceased operations or drastically downscaled customer operations at the facility." (Attachment A, Sec. 3F.) This would involve the utilities in the complex and difficult task of monitoring a customer's operations and output.

[8] Id. at 4.

Because of the above concerns, it appears that the CEC's proposal would result in a large amount of payments for load reductions that either would have occurred anyway or are phantom reductions resulting from an overly generous reference load calculation. We are concerned that these payments would be greater than any benefits from the program, even taking into account the societal benefits that would occur from any actual load reductions the program achieves.

At page 9 of its petition, CEC states its proposal places CDWR as the entity financially responsible for the payment of incentive costs or receipt of charges from RTP tariff participants and cites Executive Order D-36-01 as authorizing such financial responsibility. We share Edison's concern that the Executive Order does not explicitly designate CDWR as the responsible financial entity and agree that this issue must be resolved before we can adopt a RTP program.[9]

The CEC's proposal goes beyond a real-time pricing program by including a High Reliability Option (HRO) which would offer participants a chance to avoid both blackouts and load reductions. While ORA offers suggestions on adjustments to make this feature workable, such as setting the CBL at zero and the total surcharge at $28/kWh, we agree with PG&E that a program to allow customers to avoid blackouts should not be considered here to avoid unintentional conflict with the Optional Binding Mandatory Curtailment (OBMC) programs which the Commission has already adopted in its interruptible load rulemaking after full litigation.[10]

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[9] Edison June 28 comments at page 3.

[10] PG&E's June 26 comments at page 4.

The CEC's proposal also overlaps, and is similar to, our revised Demand Bidding Program. Both programs have as their stated purpose encouraging demand response[11]; are targeted toward the same customers; pay incentives to customers to reduce load; achieve almost all of their benefits during hours of peak energy usage; and are funded (or proposed for funding) by CDWR.

The major substantive difference is determining the reference load and whether or not CDWR is obligated to purchase the demand reductions. The Demand Bidding Program uses a 10-day baseline to calculate reference load while the CEC's program is proposing a yearly average. While not without its own limitations, and also subject to potential gaming, the use of the average energy usage over the previous ten days better reflects the effects that current energy rates and current economic conditions have on energy usage. It must be remembered that the Commission first approved the use of the 10-day average in PG&E's and Edison's Summer 2000 demand reduction proposals, a proceeding in which the CEC itself advocated for the use of a 15-day (not 10-day) average as being better reflective of actual load reductions.[12]

The second difference between the programs is whether or not CDWR is obligated to purchase demand reductions. Under the Demand Bidding Program, CDWR has the option of either accepting or not accepting bids to reduce load based on conditions in the market. Customers are also allowed to submit bids at four different price points (15, 35, 55, 75 cents/kWh) allowing the CDWR some

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[11] The CEC, for example, also filed their proposal in the Commission's rulemaking on interruptible programs (R.00-10-002).

[12] See Resolution E-3650 (April 6, 2000).

flexibility to select lower-priced bids while rejecting higher-priced bids. Under the CEC's RTP proposal, by contrast, the CDWR does not have this flexibility.[13] It would be obligated to both "purchase"[14] all load reductions that are offered and would have to pay for them at its posted real-time price.

Since both programs target the same customer groups, the CEC's proposal both competes with the Demand Bidding Program and limits the flexibility of CDWR to achieve a least-cost procurement strategy. In his letter to the Commission, Governor Davis stated his goal that the Commission "aggressively market" the Demand Bidding Program. Not adopting the CEC's proposal at this time meets the Governor's goal of allowing the Commission, CDWR, and the utilities to focus their efforts on making the Demand Bidding Program successful. Demand Bidding Program is a useful bridge to an RTP program, exposing customers to market-responsive energy planning. Approval of the CEC's program would also run counter to the Governor's stated goal to simplify demand reduction programs and avoid duplication.

Finally, there is a need to fully understand the interactions between the CEC's proposal, the Commission's recently adopted rate structure, and CDWR's revenue requirement. Although incorrectly described by some parties as "revenue neutral,"[15] any shortfalls in revenues will be made up by the CDWR,

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[13] That flexibility is retained if the posted real-time price was set purposefully low to discourage participation. Adopting this approach, however, would seriously undermine the ability of customers to plan for load reductions, which is one of the stated benefits of the CEC's proposed use of a yearly reference load calculation.

[14] The CDWR would not technically purchase load reductions but is obligated to pay for any reductions below the reference load.

[15] See, for example, the comments of CMTA.

which in turn will have to collect this shortfall through rates from all other customers. Therefore, it would be useful to have better information about the total cost of the CEC's program, and its potential for intra-class subsidies. Since a portion of the CDWR surcharge will be used to finance bonds that will be used not to pay for current energy usage but to amortize long-term bonds to reimburse the state for the cost of past- and future energy purchases, there is also a need to assess if there are any inter-generational equity issues that should be addressed.

As previously mentioned, the Commission assigned a significant portion of D.01-03-082's rate increase to on-peak energy usage in order to provide a strong incentive for customers to shift energy usage away from these hours. For example, for Edison's industrial customers, almost 15% ($160 million / year) of the rate surcharge is collected in the 4% of the hours in the year corresponding to the summer on-peak.[16] An additional 9% ($96 million) of the surcharge is collected in the 7% of the hours in the year occurring in the summer mid-peak. As these are the same hours being targeted for incentive payments to reduce load under the CEC's proposal, there is a "double whammy" effect on CDWR's revenue stream. It is not only foregoing revenues from on-peak sales but actually paying out additional monies to reduce load.

5. Next Steps

In D.01-05-064, the Commission established the broad policy guidelines that would govern the allocation of the 3 cent / kWh surcharge. These principles

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[16] Approximately 390 hours assuming a 13-week summer season. See Edison's TOU-8 rate schedules

are equally applicable to the development of any real-time pricing proposal. As the Commission stated:

> Today we adopt a rate design to achieve the following objectives: (1) reduce energy consumption and thereby reduce California's liability for exorbitant wholesale power purchases; (2) allocate these wholesale electricity purchase costs fairly among customers, consistent with statutory mandates; (3) protect the most vulnerable customers; (4) minimize the extent to which individual customers experience extreme hardship; and (5) provide customers with ways to manage their energy usage and reduce their energy bills.

The major focus of real-time pricing is clearly achievement of the last goal of providing customers with "ways to manage and reduce their energy bills," although any real-time pricing proposal must address the other criteria as well.

Applying all of the above goals to real-time pricing proposals means that any proposal adopted by the Commission should be "transparent," achieves real (not phantom) load reductions (and load shifting), meets revenue requirements (including CDWR's revenue requirements), avoids major rate shock to customers, and is equitable (in terms of avoiding cross-subsidies both between classes and across generations), and is administratively simple.

Real-time pricing should be transparent to customers, in that they know in advance how the prices will be calculated. This allows them to better plan and forecast periods when energy prices may be high and to respond accordingly. One of the concerns we have with the CEC's proposal is the "black box" nature of its real-time price calculation.

Real-time pricing should also accurately mimic the actual movement in energy prices over different time-periods. The calculation of the real time price should either be based on real prices (or if a forecasted price is used, it should be close enough to real prices to achieve the proper price signals).[17] As noted in D.01-05-064 :

> Reducing energy consumption at peak hours may also enhance system reliability when California is projected to face the severest shortages.

This does not necessarily mean that customers should always receive or pay the real-time price. As the Commission noted in D.01-05-064, given the dysfunctional nature of the current wholesale energy market, the pass through in rates of the full amount of current energy costs could cause economic hardships. Charging customers the real-time price at all times could also result in an over-collection of the utilities' revenue requirements.[18]

Real time pricing in a dysfunctional market may result in load shifting or load reductions. However, in a dysfunctional market a real time market-based price is unlikely to lead to an increase in economic efficiency or cost allocation. The price signal given by the real time price in a dysfunctional market may instead lead to less efficient decisions on the part of customers. It could also potentially lead to one set of customers, those who can participate in such load reduction incentive programs, to reap unreasonably large subsidies at the expense of those who cannot participate.

Real-time pricing proposals should also be administratively simple. This makes these programs not only easy to implement by the utilities but also easy to

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[17] This leads to the related issue of whether customers should be charged under real-time pricing proposals at either the real price or the forecasted price.

[18] This is true if the marginal cost of generation is higher than the average cost of generation.

understand by customers. Ease of administration also argues for programs where customers are charged a real-time price based on actual usage, and not by a comparison of actual usage to either forecasted or historical load data. This latter approach is difficult and complex to administer and is subject to the potential for gaming and payment for load reductions that would have occurred anyway.

In reviewing the proposals before us, we are not sure that any of them fully address all of the above requirements. As previously noted, the CEC's proposal is administratively complex and could pay for load reductions that would have occurred even without the real-time pricing program. SDG&E's one-part pricing tariff, while simple to administer, could result in significant rate increases to some customers and result in an overcollection of SDG&E's revenue requirement. Another variant of a real-time pricing proposal that parties may want to consider would be a two-part tariff (as proposed by Prof. Borenstein) in which customers receive some portion of their load at fixed prices and some portion at real-time prices. For example, customers could receive the 50-60% of their energy usage currently being provided by retained generation at the cost-of-service for providing this generation, and then pay spot prices for the remainder of their usage. These figures could be adjusted over time to reflect the utilities' and CDWR's procurement of additional long-term contracts and variations in load over different time periods. Other variations of a two-part tariff could also be considered.

Finally, parties may want to consider real-time pricing proposals that contain such features as price caps, floors, and rate limiters. It was these types of mechanisms that the Commission utilized in assisting large customers in transitioning from fixed to time-of-use rates during the late-1980's to early-

1990's. Similar features could be developed to address similar concerns in the movement toward real-time pricing.

Using the criteria we discuss here, we direct PG&E, Edison, SDG&E, and invite any other interested parties to file an RTP proposal in this proceeding on August 17, 2001.

6. Comments on Draft Decision

The draft decision was mailed on July 19, 2001 with comments due on July 26, 2001. Pursuant to Rule 77.7(f)(9) of our Rules of Practice and Procedure, we reduce the 30-day period for public review and comment because public necessity requires that we act on this matter prior to the 30-day period. Edison, the CEC, Environmental Defense, Internal Services Division of Los Angeles County (Los Angeles), PG&E, and TURN filed comments on the Proposed Decision.

Edison and PG&E are generally supportive of the decision. Environmental Defense and TURN urge the Commission to adopt the CEC's proposal, if only as a "pilot program" for this summer. Environmental Defense would approve the program on a pilot basis even if, retrospectively, "the majority of participants are found to be free riders."[19]

CEC offered extensive comments in support of its proposal, and in an attachment, offers a revised version of its RTP proposal. Edison and PG&E both committed to offering by August 17 their own RTP proposals for the Commission's consideration, although Edison notes the current difficulties in developing a "transparent" price for energy.

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[19] Environmental Defense Comments, p. 2.

While the CEC's revised version removes the High Reliability Option and eliminates the ability of customers to "customize" their own baseline calculation, we continue to have concerns with other portions of the CEC's revised proposal, particularly their continued use of individual customer baselines and the administrative complexity of their program. We will further consider the CEC's revised proposal in conjunction with our review of all RTP proposals submitted on August 17, 2001.

While all parties supported the mandatory installation of meters, Edison, Los Angeles, and PG&E argue that customers should not be required to either participate in a demand response program or shift to a TOU rate. If required to do so, customers should be given substantially longer to decide than the 15 days currently proposed. Instead, customers should be given a time-period somewhere between 60 days (Los Angeles) to 4 months (Edison), with PG&E proposing a 90-day time-period.

Edison and PG&E also argue that the existing TOU rates are inappropriate for many customers and that as a result customers may sign up for demand responsiveness programs instead.[20] Since many of these demand responsiveness programs allow for voluntary participation once a customer signs up, Edison argues that customers will sign up for these programs and then decline to participate.

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[20] Actually, this either/or choice is incorrect. Nothing in today's decision precludes a customer from signing up for a demand responsiveness program within 15-days of receiving a meter and then subsequently shifting to a TOU rate if they desire to do so. As customers are able to review their actual usage patterns after receipt of a meter we would expect some customers to change to TOU rates.

Based on PG&E's and Edison's comments, we should consider two revisions to the notice and options for customers receiving an interval meter who are not currently on a TOU schedule. First, we should further explore PG&E's proposal of a revenue neutral TOU rate schedule for customers currently on the A-10 schedule. PG&E proposes that instead of switching these customers to the E-19 TOU schedule, we instead apply the E-19 TOU surcharges to the existing A-10 schedule. This would provide the incentive for these customers to reduce on-peak energy usage while not subjecting them to the higher demand charges of the E-19 schedule. We would like to examine this in further detail. PG&E and Edison are directed to file a complete revenue neutral TOU proposal, with supporting workpapers, by August 8, 2001. Interested parties should comment on these proposals by August 15, 2001.

The second revision we should consider is customer notice. A 15-day period should be adequate notification if the utilities also send a letter beforehand advising customers of the choices they will need to make when they receive their meters under the AB1X 29 program and how to contact a customer service representative for further information and assistance. Based on the installation priority we establish in this decision, smaller customers who are not currently enrolled in a demand reduction program will be the last to receive the AB1X 29 meters. They will effectively receive more than 15 days notice. PG&E and Edison should submit a draft notification letter on August 8 with their TOU proposal.

The changes we will consider do not change the modified language we adopt for D.01-05-064 but rather will provide an additional form of notification and the possibility of an additional TOU schedule.

Findings of Fact

1. The receipt of TOU or RTP meters for customers with electric loads over 200 kW of peak demand is mandatory under ABX1 29.

2. CEC has chosen to use the $35 million allocated by the Legislature under ABX1 29 to install RTP metering systems for customers.

3. Customers receiving RTP meters under ABX1 29 who are not on a TOU schedule should be given the option of either enrolling in a demand reduction program or receiving service under TOU schedules to ensure that the state’s metering investment delivers the benefit of reducing California’s energy demand, especially at times of supply shortages.

4. RTP issues relating to SDG&E were transferred from A.00-10-045 and A.01-01-044 to this proceeding by ALJ Mark Wetzell on June 1, 2001.

5. The proposed RTP tariff contained in CEC’s June 12, 2001 Petition to Modify D.01-05-064 contains a calculation of reference load that is overly generous and subject to extensive gaming.

6. Sufficient information is not available about the total cost of the CEC’s program or its potential for intra-class subsidies for the Commission to determine that this proposal is reasonable.

7. The CEC’s RTP is not a true RTP program.

8. Most of the claimed benefits from the CEC’s RTP proposal likely can be achieved by the modified Demand Bidding Program the Commission adopted in D.01-07-025.

9. RTP should provide customers with an effective way to manage and reduce their energy bills.

10. RTP should be transparent to customers, in that they know in advance how the prices will be calculated.

11. RTP should accurately mimic the actual movement in energy prices over different time-periods.

12. RTP should achieve real load reductions and load shifting.

13. RTP proposals should be administratively simple and easy for customers to understand.

14. RTP should meet revenue requirements (including CDWR's revenue requirement), avoid major rate shock to customers, and be equitable in terms of avoiding cross-subsidies among classes.

15. Additional customer notification and exploration of the possibility of an additional TOU schedule would be beneficial.

Conclusions of Law

1. The CEC's May 17, 2001 petition to modify D.01-05-064 should be granted, in part, as follows:

   a. Section V.A., **Moving to Time of Use Meters for Commercial Customers**, should be modified by deleting the last two paragraphs of the section (mimeo. at 32) and replacing them with the following language:

> Pursuant to ABX1 29, the CEC is authorized $35 million for the installation of TOU or Real Time Pricing (RTP) metering systems on all customers with electric loads over 200 kW of demand. Under this mandatory program, the CEC has chosen to install RTP rather than TOU metering systems. RTP metering systems provide the communication capabilities necessary for customers to participate in specific load reduction programs, demand reduction programs, administered by the Commission, the ISO, and CDWR. These programs, including the proposed Demand Bidding Program (DBP), currently pending before the Commission in R.00-10-002, offer customers incentives for reducing energy consumption and demand during high net short periods. In order for California to realize the benefits of ABX1 29

> metering expenditures, all customers who receive the meters should be on a demand reduction program as listed in the revised Attachment A to D.01-04-006 or placed on a TOU schedule. Customers should make this election within 30 days of installation of the new metering system. Customers failing to choose a demand reduction program or TOU schedule shall be placed on a TOU schedule.

b. Section VII.B., **Expedited Installation of Meters**, should be modified by adding at the end of the section the following paragraph:

> To ensure effective monitoring of timely installation of the meters we should require PG&E, Edison, and SDG&E to provide a bi-weekly report until all ABX1 29 metering systems are installed that lists the number of RTP metering systems installed and the selection made by the customer of a demand reduction program (DRP), as set forth in revisions to Attachment A of D.01-04-006 or enrollment on a TOU schedule. The utilities should prioritize the installation of these meters to first include customers who are enrolled in a demand reduction program and then proceed to customers with the highest kW peak demand level.

2. The CEC's June 21, 2001 petition to modify D.01-05-064 should be denied.

3. PG&E, Edison, SDG&E, and any other interested parties, should file an RTP proposal in this proceeding no later than August 17, 2001 that meets the criteria discussed here.

4. PG&E and Edison should file on August 8, 2001 a draft customer notification letter and a revenue neutral TOU proposal, with supporting workpapers, for customers receiving an ABX1 29 meter who are not on a TOU schedule. Interested parties should file comments on these proposals by August 15, 2001.

5. In order to expeditiously implement ABX1 29, this order should be effective immediately.

INTERIM ORDER

IT IS ORDERED that:

1. The California Energy Commission's (CEC) May 17, 2001 Petition to Modify Decision (D.) 01-05-064 is granted, in part, as follows:

   a. Section V.A., **Moving to Time of Use Meters for Commercial Customers**, shall be modified by deleting the last two paragraphs of the section (mimeo. at 32) and replacing them with the following language:

      > Pursuant to ABX1 29, the CEC is authorized $35 million for the installation of TOU or Real Time Pricing (RTP) metering systems on all customers with electric loads over 200 kW of demand. Under this mandatory program, the CEC has chosen to install RTP rather than TOU metering systems. RTP metering systems provide the communication capabilities necessary for customers to participate in specific load reduction programs, demand reduction programs, administered by the Commission, the ISO, and CDWR. These programs, including the proposed Demand Bidding Program (DBP), currently pending before the Commission in R.00-10-002, offer customers incentives for reducing energy consumption and demand during high net short periods. In order for California to realize the benefits of ABX1 29 metering expenditures, all customers who receive the meters should be on a demand reduction program as listed in the revised Attachment A to D.01-04-006 or placed on a TOU schedule. Customers should make this election within 15 days of installation of the new metering system. Customers failing to choose a demand reduction program or TOU schedule shall be placed on a TOU schedule.

   b. Section VII.B., **Expedited Installation of Meters**, shall be modified by adding at the end of the section the following paragraph:

      > To ensure effective monitoring of timely installation of the meters we should require PG&E, Edison, and SDG&E to provide a bi-weekly report until all ABX1 29 metering systems

are installed that lists the number of RTP metering systems installed and the selection made by the customer of a demand reduction program (DRP), as set forth in revisions to Attachment A of D.01-04-006 or enrollment on a TOU schedule. The utilities should prioritize the installation of these meters to first include customers who are enrolled in a demand reduction program and then proceed to customers with the highest kW peak demand level.

2. CEC's June 12, 2001 Petition to Modify D.01-05-064 is denied.

3. Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, and any other interested parties, shall file an RTP proposal in this proceeding no later than August 17, 2001 that meets the following criteria:

a. Provides customers with an effective way to manage and reduce their energy bills;

b. Is transparent to customers, in that they know in advance how the prices will be calculated;

c. Accurately mimics the actual movement in energy prices over different time periods;

d. Is designed to achieve real load reductions and load shifting;

e. Meets revenue requirements, including California Department of Water Resources' revenue requirement, avoids major rate shock to customers, and is equitable in terms of avoiding cross subsidies among customer classes; and

f. Is administratively simple and easy for the customer to understand.

4. PG&E and Edison shall file on August 8, 2001 a draft customer notification letter and a revenue neutral TOU proposal, with supporting workpapers, for customers receiving an ABX1 29 meter who are not on a TOU schedule. Interested parties shall file comments on these proposals by August 15, 2001.

This order is effective today.

Dated August 2, 2001, at San Francisco, California.

LORETTA M. LYNCH
President
RICHARD A. BILAS
CARL W. WOOD
GEOFFREY F. BROWN
Commissioners

Commissioner Henry M. Duque, being necessarily absent, did not participate.

I will file a concurrence.

/s/ RICHARD A. BILAS
Commissioner

A.00-11-038
D.01-08-021

Commissioner Bilas, concurring:

While I support this order, I do so with some caveats. While there are problems with the Real Time Pricing proposal of the CEC, it is difficult to support an order denying its implementation because I believe real time pricing works. Had we deployed interval meters and switched to real time pricing before the summer of 2000, California markets would not be in the present dysfunctional state. I believe that the CEC is correct to assert that in order to get full value for the $35 million spent on these sophisticated meters, their capabilities must be utilized fully. So I would prefer to approve the CEC proposal with modifications. While we will still persevere in making workable modifications, I would have preferred to resolve all the issues in this decision so we could move to immediate implementation.

There are also aspects of this decision that I find problematic. I wholeheartedly disagree with its assertion that we cannot find a transparent real time price upon which to base the program. There are many competent exchanges that could serve such a function. I completely disagree with the decision's assertion that due to the DWR power purchases, the societal benefits of real time pricing become less and even negative if it resells power at a loss. We should be focusing on getting the DWR out of markets so overprocurement will cease, not using the DWR's procurement mistakes as a rationale to torpedo real time pricing. Finally, I do not like the decision's rejection of the High Reliability Option permitting an option for participants to pay more in order to obtain more reliability. Even ORA supports this concept with adjustments to make it more workable. I urge my colleagues to support this approach. Business should be able to pay a premium for reliability. Such a premium would inure to the benefit of all ratepayers' rates.

For these reasons, I respectfully concur.

/s/ RICHARD A. BILAS

RICHARD A. BILAS
Commissioner

San Francisco, California
August 2, 2001